U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-295/89021(DRP); 50-304/89019(DRP)

Docket Nos. 50-295; 50-304 License Nos. DPR-39; DPR-48

Licensee: Commonwealth Edison Company
P. O. Box 767
Chicago, IL 60690

Facility Name: Zion Nuclear Power Station, Units 1 and 2

Inspection At: Zion, IL

Inspection Conducted: June 30 through August 31, 1989

Inspectors: J. D. Smith
R. J. Leemon
A. M. Bongiovanni
V. Rooney

Approved By: J. M. Hinds, Jr., Chief SEP 19 1989
Reactor Projects Section 1A Date

Inspection Summary

Inspection from June 30 through August 31, 1989 (Report Nos. 50-295/89021(DRP); 50-304/89019(DRP))

Areas Inspected: Routine, unannounced resident inspection of licensee action on previous inspection findings; summary of operation; operational safety verification and engineered safety feature (ESF) system walkdown; power oscillation on Unit 2 on June 30, loss of Unit 1 control room annunciators on July 6, unidentified reactor coolant leakage for Unit 2 on July 22 and August 12, inadequate auxiliary feedwater flow settings for Unit 1 on July 23, administrative overexposure of a technician on August 18; and electro hydraulic control (EHC) fluid leak on Unit 1 on August 21, reactor coolant system pressure below Technical Specification limit on Unit 1, and security events; surveillance observation; maintenance observation; licensee event reports (LERs); training; quality program effectiveness, TI 2500/27.

Results: Of the nine areas inspected, no violations or deviations were identified in six areas, and three violations were identified in the remaining three areas (1) Two examples of failure to follow written procedures, Paragraph 5; (2) Failure to perform post installation or post modification testing, Paragraph 2; and (3) Failure to perform task with adequate procedure, Paragraph 4.

8910160005 890920
PDR ADOCK 05000295
Q PNU

DETAILS

1. Persons Contacted

Commonwealth Edison

T. Joyce, Station Manager
*W. Kurth, Superintendent, Production
*T. Rieck, Superintendent, Services
*P. LeBlond, Assistant Station Superintendent, Operations
*R. Johnson, Assistant Station Superintendent, Maintenance
R. Budowle, Technical Services Director
N. Valos, Unit 2 Operating Engineer
W. Demo, Unit 1 Operating Engineer
M. Carnahan, Operating Engineer
E. Broccolo, Jr., Director of Performance Improvement Program
T. Vandevoort, Quality Assurance Supervisor
*C. Schultz, Quality Control Supervisor
*W. Stone, Regulatory Assurance Supervisor
W. T'Niemi, Tech Staff Supervisor
F. Smith, Security Administrator
*T. Sakserski, Regulatory Assurance
*W. Mammoser, PWR Projects

US NRC

*D. Calhoun, Project Inspector

*Indicates persons present at the exit interview.

The inspectors also contacted other licensee personnel including members of the operating, maintenance, security, and engineering staff.

2. Licensee Actions on Previous Inspection Findings (92701, 92702)

(Closed) Unresolved Item (304/89015-02(DRP)): Loss of Unit 2 Control Room Annunciators due to incorrect wire connection in the emergency power supply circuit. On June 24, 1989, normal power was lost to all Unit 2 control room annunciators when power was switched to the emergency supply. All power supply fuses blew when this transfer was made. Investigations by the licensee showed a reversed lead in the emergency power supply circuit which apparently existed since initial installation. No post modification or post installation testing was performed which would have identified this problem. The licensee has verified correct polarity on all 57 emergency power supplies to ensure that no other reversed leads existed. Failure to perform a test to verify installation or applicable design criteria is contrary to 10 CFR 50, Appendix B Criterion XI and is considered a violation. (304/89019-01(DRP)). This unresolved item is considered closed.

(Closed) Violation (295/89017-01(DRP)): Continued operation in excess of the Technical Specification (TS) limits with 1A containment spray system inoperable due to the failure of 1MOV-CS-0049. In their response to the violation, the licensee committed to review generic operability issues, upgrade the LCO determination capabilities and review TS for possible revision to include recirculation phase functions. These changes are not scheduled for implementation until October 1989. The implementation and completion of the corrective actions will be tracked by Open Item (295/89021-01(DRP)). This violation is considered closed.

(Closed) Detailed Control Room Design Review (DCRDR) (MPA-F008; I.D.1.1.) for Unit 1 and Unit 2.

Commonwealth Edison submitted a Generic DCRDR Program Plan in March 1984 to respond to Supplement 1 of NUREG-0737. This plan outlined Commonwealth Edison's response for each of the six nuclear generating stations.

The Final Summary Report submitted for Zion identified 441 individual Human Engineering Discrepancies (HEDs). These HEDs were submitted with a proposed schedule for implementation in accordance with the Program Plan. The implementation of corrective actions for each HED was scheduled to extend over three refueling outage schedules for each Unit. The review of the DCRDR has been completed.

Zion Unit 1 will undergo its Second Refueling Outage beginning in September 1989, and Unit 2 in March 1990. The bulk of the HEDs requiring corrective actions are scheduled to be done for each unit during its respective second refueling outage (approximately 160 HEDs). After completion of the Unit 2 second refueling outage the only HEDs that will not have corrective actions taken are those which have been deferred by the NRC. These HEDs are related to the Unit 1 radiation monitor recorders that were installed and will be replaced, and the redesign of the chemical and volume control system (CVCS) panel to allow for the incorporation of two other modifications affecting the CVCS. The replacement of the radiation monitor recorders is scheduled to be completed by March 1991, and the CVCS modification will be implemented during each Unit's respective third refueling outage (Spring 1991 for Unit 1 and Fall 1991 for Unit 2).

<u>Inspection for Verification of Licensee Changes Made to Comply with PWR Moderator Dilution Requirements -- Multi-Plant Action Item B-03</u>

The inspector reviewed licensee records related to the disposition of the PWR Moderator Dilution Requirements, Multi-Plant Action (MPA) Item B-03. Multi-Plant Item B-03 originated when an unreviewed method of moderator dilution was revealed by an incident at an operating PWR facility. With the reactor in the cold shutdown condition, a portion of the contents of the NaOH tank gravity drained into the Decay Heat Removal System during surveillance cycling of a tank isolation valve and was subsequently injected into the reactor coolant system. Licensee evaluation of this incident revealed that unterminated injection of NaOH solution could result in reactor criticality and that this manner of moderator dilution was not bounded by FSAR analysis. DOR Information Memorandum No. 7, PWR Moderator Dilution, was issued on October 4, 1977. Operating PWR licensees were informed of the incident and requested to evaluate potential moderator dilution accidents for their facilities.

Inspection efforts at Zion Station produced no record of the licensee being requested to report, or of the licensee reporting the results of the evaluation to the staff. Licensee correspondence and vendor analysis for this safety issue were plant specific for Zion Station. The only situation identified by the vendor as requiring correction was inadvertent boron dilution while on RHR with a shutdown margin less than 5%. The vendor concluded that the threat of an unacceptable inadvertent dilution was removed by closing valves in the reactor makeup water supply and valves between the boric acid blender and the volume control tank. The licensee accepted the vendor's analysis of the concern, and has incorporated the recommendations into procedure PT-0, App. E-3, Operating Surveillance Checksheet Cold Shutdown (Mode 5), as requirements when the plant is on RHR with a shutdown margin of less than 5%.

At the inspectors request the licensee agreed to add a footnote to the procedure relating these requirements to NRC safety issue MPA B-03 so that the origin is preserved, and the requirements are not inadvertently deleted. The actions taken by the licensee appear to be satisfactory.

The inspector concluded that completion of MPA B-03 is verified for the Zion Station.

One violation and no deviations were identfied.

3. Summary of Operations (71707)

Unit 1

The unit operated at power levels up to 100% until August 21, 1989, when the unit was taken off-line and placed in Hot Standby due to an EHC fluid leak from a crack in the common supply line to the #2 and #4 stop and governor valves. Power ascension resumed on August 22. On August 26, it was determined that sixteen of the twenty main steam safety valves (MSSVs) were potentially inoperable so the unit was placed in hot shutdown. The unit was placed back on-line on August 31.

Unit 2

The unit operated at power levels up to 100% until July 29, 1989, when power was decreased to 40% to perform maintenance on the pressurizer spray valve (PSV) due to excessive packing leakage. On August 12 power was decreased to 60% due to a reactor coolant system (RCS) leak rate of 2.5 gpm. Excessive packing leakage from the PSVs was the cause of the increased leak rate.

No violations or deviations were identified.

4. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs and conducted discussions with control room operators from June 30 through August 31, 1989. During these discussions and observations, the inspectors ascertained that the operators were alert, cognizant of plant conditions, attentive to changes in those conditions, and took prompt action when appropriate. The inspectors verified the operability of selected emergency systems, reviewed tagout records and verified proper return to service of affected components. Tours of the auxiliary and turbine buildings were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance.

The inspectors by observation and direct interview verified that selected physical security activities were being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under Technical Specifications, 10 CFR, and administrative procedures.

a. Power Oscillations

At 3:50 a.m. on June 30, 1989, unit 2 was stable at 57% power when the C-7 interlock light lit indicating a turbine load rejection of greater than 10% power. The Nuclear Station Operator (NSO) then noticed the generator output oscillating approximately 50 megawatts and that the #2 and #3 govener valves were swinging. The NSO took manual control of the turbine. At this time the generator output increased approximately 300 megawatts to 900 megawatts. The NSO immediately reduced the generator's output to approximately 500 megawatts and the unit stabilized. The peak nuclear power during the incident was 72%. The plant transient was terminated by prompt operator action.

The apparent cause of the event was a broken wire at a linear variable differential transformer which provides governor valve position indication feedback to the electro hydraulic control system (EHC). Without proper feedback information of valve position, the EHC system controlled the #4 governor valve erratically, causing load swings as described above. The licensee repaired the broken wire which solved the oscillation problem.

The power increase caused pressurizer pressure to drop to 2150 psig for approximately one minute, but later returned to above 2205 psig, the Technical Specification low pressure limit. TS states that the limit is not applicable during a thermal power ramp increase in excess of 5% rated thermal power per minute or a thermal power step increase in excess of 10% rated thermal power.

b. Loss of Unit 1 Control Room Annunciators

On July 6, 1989, at 1:22 a.m., an Unusual Event (UE) for Nuclear Steam Supply System (NSSS) Annunciators was declared for Unit 1.

The annunciators could not be silenced using the main control board push button. The horn power supply card was pulled to silence the horn which resulted in the loss of all audible annunciators. However, the alarm windows would still flash when an alarm condition occurred but the alarm could not be acknowledged or reset. The licensee took precautionary measures which included cancelling the scheduled load drop and posting additional operators on the main control boards to monitor instrumentation. The horn malfunction was caused by the failure of a control system circuit card. The card was replaced and tested satisfactory. At 7:15 a.m., the UE was terminated.

c. Unidentified Reactor Coolant Leakage for Unit 2

On July 22, 1989, at approximately 2:00 p.m., with Unit 2 at 99.3% power, an unidentified reactor coolant system leak rate of 4.3 gpm was computed. Technical Specifications permit operations to continue for up to 24 hours if unidentified leakage exceeds 1 gpm. After investigating several relief valves for leakage without success, the licensee declared an UE at 3:50 p.m.

Reactor power was reduced to 40% to permit entry into the containment. The pressurizer spray valve 2PCV-RC06 and its associated manual isolation valve were found with packing leaks. The redundant pressurizer spray valve, 2PCV-RC07, was placed in service. While preparing the valve for service in auto control, a slight overshoot in the manual control mode caused a pressure transient whereby, pressurizer pressure dropped to 2197 psig for approximately four minutes. The unit pressure was rapidly stabilized and the Generating Station Emergency Plan (GSEP) UE was terminated at 10:30 p.m. when RCS leakage was less than 1.0 gpm. The 2PCV-RC06 valve was repaired and left isolated for redundancy. (See Paragraph 6)

On August 12, 1989, at approximately 4:20 p.m., the Unit 2 NSO noticed that the pressurizer relief tank level was increasing. He also noticed that the volume control tank level had been on a downward trend for approximately one hour. A leak rate calculation was performed and the RCS leak rate was determined to be 2.3 gpm. It was believed that the packing on 2PSV-RC07 was leaking. At 6:35 p.m., an UE was declared due to the leakage

Power was reduced to 60% to allow personnel entry into containment. At this time 2PVC-RC06 was isolated and 2PVC-RC07 was placed in-service and currently being used for reactor coolant system pressure control.

Prior to entry into the containment the Shift Engineer (SE) informed the Shift Foreman (SF) that he wanted 2PCV-RC06 unisolated and 2PCV-RC07 isolated in that sequence. Before the unit reached 60% power the SF briefed two "B" men (plant operators) and he reviewed the plant flow prints to verify which valves were to be operated. The Shift Control Room Engineer (SCRE) decided to go into containment with the crew, which included the SF and two "B" men. The SE did not designate the SCRE or the SF as the person in charge; and assumed that they would work together and that the SF would brief the SCRE.

The SE expected to receive a phone call from the crew in containment after the 2PCV-RC06 had been unisolated and prior to isolating 2PCV-RC07. The phone call was never made. The SE did not notice anything unusual until the Unit 2 HIGH/LOW pressure and the pressurizer deviation alarms came in. The SE not knowing whether or not the valve was isolated, left the manual auto station for 2PCV-RC06 in the closed position and controlled system pressure with the pressurizer heaters. The SE sent another "B" man into containment to have the crew call the control room.

The SCRE called a few minutes later and informed the SE that 2PCV-RC06 was unisolated and 2PCV-RC07 was isolated. The NSO then tried to control pressure with 2PVC-RC06 without success.

Later, the SCRE and the SF returned to the SE's office to discuss the communications problem which had occurred. The SE questioned the SCRE and SF of what they had done, specifically asking if both upstream and downstream isolation valves on 2PCV-RC06 were opened. The SCRE said that only the upstream isolation valve had been opened. Another containment entry was made to fully unisolate 2PCV-RC06.

The root causes of the problem were poor communications and inadequate pre-job briefing in that the specific duties to be performed, prior to containment entry, were not assigned. Failure to provide an adequate briefing on the evolution to be performed prior to containment entry is considered a violation (304/89019-02(DRP)).

This is the second example of poor job planning by the operating staff. (see Inspection Reports 89015; 89015, section 4). The residents will be reviewing the root causes for possible generic problems in the SF and SCRE training programs.

d. <u>Inadequate Auxiliary Feedwater (AFW) Flow Setting Below FSAR Analysis</u>

At 6:40 p.m. on July 23, 1989, the 1A turbine driven auxiliary feedwater (AFW) pump was declared inoperable due to failing a trip test. The motor driven AFW pumps were realigned to provide two operable flow paths to the steam generators (S/G). The S/G flow control valves were not readjusted to the correct positions to insure that minimum TS requirements were met. The flow rates provided to the S/Gs were not verified to be 105 gpm to each S/G, within eight hours as required by Technical Specifications 3.7.2.d and 4.7.2.A.1.6.

On July 24, the 1B AFW pump was operated and flows were determined to be 97 gpm to the "A" S/G, 88 gpm to the "B" S/G, 99 gpm to the

"C" S/G, and 92 gpm to the "D" S/G. All flows were properly reset to 105 gpm to each S/G at 11:48 a.m. on July 24. The apparent cause of the event was an administrative error in the interpretation of applicable Technical Specifications when declaring the 1A AFW pump inoperable.

The safety significance of the degraded flow situation is being analyzed by the licensee's Nuclear Fuel Services Department. This is considered an Unresolved Item (295/89021-02(DRP)) pending review of the analysis.

e. Administrative Overexposure

On August 18, 1989, an administrative overexposure occurred during the replacement of a switch for the fuel transfer cart position in the fuel transfer canal. The four workers involved were approved for an exposure of up to 500 mrem. A radiation technician was monitoring the work activity from the fuel building floor. Upon exiting the fuel transfer canal, two of the worker's digital dosimeters were alarming. Their badges were pulled for emergency processing and read 434 mrem and 1009 mrem respectively. The apparent cause of the overexposure was due to a misinterpretation of the 4 R/hr hot spot to be an extremity exposure instead of a whole body exposure. Subsequent surveys showed an additional field of 6 R/hr which was not identified on the initial survey. This new field was apparently blocked by the fuel transfer cart during the initial survey. An evaluations committee met to determine the cause of the overexposure and the corrective actions. This is considered an Open Item (295/89021-03(DRP); 304/89019-03 (DRP)) pending review of the procedure revisions.

f. Unit Shutdown Due to EHC Fluid Leak on Unit 1

On August 21, 1989, at approximately 9:30 p.m., unit operators received a low Electro Hydraulic Control (EHC) level alarm on Unit 1. Investigations showed a circumferential crack in the common supply line to the #2 and #4 stop and governor valves. Power was reduced and the unit was taken off-line at 10:30 p.m.

The plant was maintained in a critical condition at approximately 1% power by withdrawing the control rods and diluting the reactor coolant system. The core was at end-of-life and dilution did not keep up with xenon build-in. Therefore, Tave dropped to a low of 503°F. The EHC system leak was repaired with a fillet weld. The unit was placed back on-line on August 23 at 5:07 a.m and power was increased to 40% to perform MSSVs Testing.

g. Unit 1 - Reactor Coolant System Pressure Less than 2205 psig

At approximately 12:44 a.m., on August 27, 1989, while at 3% power and shutting down the plant due to inoperable MSSVs, the reactor coolant system pressure dropped below the Technical Specification limit of 2205 psig. The lowest pressure reached was 2170 psig.

Within two to three minutes the pressure returned above the TS limit. Technical Specification 3.2.3.D.1.4.B allows two hours to return the parameter to above the limit, therefore, the Technical Specification was not violated.

h. Security Events

During a routine unannounced inspection by the regional safeguards inspectors, several examples of degraded vital/protected area barriers were found. The licensee implemented compensatory measures and assigned extra guards to patrol the areas in question. The licensee initiated independent inspections of the Turbine Building to determine if other potential degraded barriers existed. This inspection showed other weaknesses to which the licensee took appropriate compensatory measures.

On August 17, 1989, a security guard was arrested by the Zion, Illinois police and charged with three counts of armed robbery. The guard's site access was terminated. It was determined that the individual was accompanied by one or more persons at all times that he was within the plant protected area. He was a new employee who first received site access on August 11, 1989. The regional security inspectors are following this event.

One violation and one unresolved item were identified.

5. Monthly Surveillance Observation (61726)

The inspector observed Technical Specifications required surveillance testing on the Main Steam System and verified whether testing was performed in accordance with adequate procedures, whether test instrumentation was calibrated, whether limiting conditions for operation were met, whether removal and restoration of the affected components were accomplished, whether test results conformed with technical specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and whether any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspector also witnessed or reviewed portions of the following test activities:

PT-0	Appendix J-2	Onsite AC-DC Power Availability
PT-0	Appendix S	Equipment Operator Checklist
PT-0	Appendix W	Turbine Building Checklist #2
PT-6		Containment Spray System Tests and Checks
PT-10	Various Portions	Safeguards Actuation
PT-202		Fire Protection Pumps Capacity Tests

IMP-NR-4	Rescaling NIS N42 Detector Currents
PT-5A	Reactor Protection Logic, Reactor at Hot Shutdown

The following observations were made.

a. Annual Capacity Test for Fire Pumps

On June 27, 1989, PT-202, Fire Protection Pumps Capacity Test, was performed. The 0B diesel driven fire pump was tested first and initial calculations from the test data resulted in very low flow measurement. The procedure was continued for the 0A motor driven fire pump. The differential pressure measurements from the in-line annubar were very low for the 0A pump also. Calculations for both pumps were verified and graphed per the procedure. Neither pump met the acceptance criteria and both were declared inoperable at 3:00 p.m. on June 27, 1989.

Since the flow capabilities for both pumps were very low, the annubar probe, which measures the velocity and static pressure differential in the test pipe, was suspected of providing erroneous data. The annubar consists of two pitot-type probes which are mounted inside the pipe where the flow is to be determined. The velocity probe is a tube which has holes that face directly into the flow. The static probe has one hole which faces directly opposite the flow. Both of these tubes can rot[illegible]d are held in place by tightening their collar nuts. A diffe[illegible]l pressure gauge is connected to each probe and a differential pressure is recorded. By maintaining the annubar flow constant, the flow in the pipe can be determined. Rotation of these tubes by more than three degrees from their prescribed orientation will cause the differential. This data will then cause the flow calculations to become lower than the actual flow in the pipe.

Inspection of the annubar showed that the holes in both probes were mispositioned. It is suspected that the annubar may have been bumped or installed incorrectly to cause the probes to be rotated. Both probe collar nuts were found to be firmly tight but, not to the point where they could not be rotated. The probes were cleaned, aligned properly, and the annubar was inserted back into the pipe. On June 30, PT-202 was performed again; at which time both pumps met the acceptance criteria and were declared operable.

To prevent this event from occurring again, the procedure, PT-202, will be revised to include inspection, cleaning, and verification of proper alignment of the annubar before the test is performed.

This is an Open Item (295/89021-04(DRP)) pending the review of the revised procedure.

b. NIS Testing

On July 20, 1989, it was discovered at 3:35 p.m. that the Unit 2 N42 channel operation selector switch was not placed in the "normal" position following a channel surveillance. The operator performed a thermocouple PT-14C test and placed the switch to the correct position. The switch permits calibration of the channel potentiometers which could increase or decrease the delta flux and power inputs to the process computer. The potentiometers were believed to be at the zero position indicating that the signals received were true values and were not affected by the switch position. A review of procedure, IMP-NR-4, "Rescaling NIS N42 Detector Currents," indicated that the technician signed off the step that the switch was returned to the NORMAL position. Testing of the N42 channel was completed by noon and subequently the channel was returned to service, except that the operator selector switch was not placed in the NORMAL position. Channels N43 and N44 were tested later that day and were placed in the test position. Technical Specification 3.1.2.b states that only one channel of a particular protection set shall be tested at a time. Discussions with the unit operator and IM personnel, revealed that only one channel was in the test position at a time due to the physical arrangement of the channel select test switch.

Discussions with the licensee indicated that the root cause was attributed to personnel error and procedure inadequacy. The procedure for N42 does not have double verification or separate steps for manipulating the operation selector switch and the test potentiometers.

Failure to conduct IMP-NR-4 in accordance with written procedures is one of two examples of the licensee's failure to follow procedures. This is considered a violation (304/89019-04(DRP)).

c. Periodic Test (PT) - 5A

On February 27, 1989, PT-5A "Reactor Protection Logic, Reactor at Hot Shutdown" was performed. During this test a jumper was installed in the reactor protection cabinet (1C) 1CB30 between jumper terminals 4L24-7 and 4L25-8. The status light in the control room for the turbine stop valve was disabled; due to the jumper causing a continuous open indication signal of valve position. A closed signal on four out of four turbine stop valves or tripping two out of three low pressure auto stop oil relays will trip the turbine and initiate a reactor trip. Since the jumper prevented a closed signal on one of the four stop valves, the four/four trip function was defeated for Train A. However, if all four valves were closed, the auto stop oil trip logic would have been made up due to the fact that the auto stop oil trip physically occurs prior to the four/four stop valve trip. The reactor would trip even if the subject jumper was installed. Also, Train B logic was available throughout the event. On February 28, the column of the procedure labeled "Jumpers Removed/Person Initials" was initialed for terminal board 4L25, jumper (7-8) and the "Person Removing Jumpers" blank was signed.

On July 11, while performing a walkdown in the reactor protection cabinet (IC) 1CB30, a technical staff engineer noticed an unmarked jumper. The jumper connected terminals 4L25-7 and 4L25-8. It appears that this jumper was not removed after PT-5A was performed in February 1989.

The apparent cause of this event has been determined to be personnel error in that a jumper was not properly removed following testing. A contributing factor to the event was the lack of independent verification for jumper installation and removal in PT-5A.

Failure to conduct PT-5A in accordance with written procedures is considered a violation (295/89021-05(DRP)).

d. Main Steam Safety Valves (MSSVs) Testing

On August 23, 1989, the resident inspectors witnessed the preparation and testing of the Unit 1 MSSVs performed by Furmanite Company personnel and assisted by the station's maintenance department. The unit was at approximately 40% power. Although the licensee is required by TS 4.7.1 to test the setpoints of ten of the twenty MSSVs, the licensee planned to test all MSSVs due to past problems. (See Inspection Report 295/89015(DRS))

By August 24, eight valves had been tested with seven valve set points found outside of the TS 1% acceptance criteria. Test data showed that one of the MSSVs as-found lift pressure was 1004 psig, which is below the Hot Standby pressure of 1005 psig at 547°F TAVG. The unit was placed in Hot Standby earlier in the week to perform work on the EHC system; however, it was believed that the valve did not lift during that time period. The licensee reviewed the data from the past week for the three permanently installed pressure transmitters on the steam header. This data indicated that steam pressure was 1010 psig for several minutes on two of the instruments during the Hot Standby condition. Due to the difference in the location of steam header measurement points and instrument accuracies of the Furmanite TREVITEST equipment used, it was not clear which set of pressure data was inaccurate. Based on these uncertainties, additional tests were performed on August 26. Simultaneous pressures were obtained by using two different electronic pressure gauges to measure the steam header pressure in the pipe tunnel and in the MSSV valve house for all four steam headers. No conclusions could be drawn since the data obtained was not repeatable. The investigation continued with a test rig containing the two digital electronic gauges and a heise gauge. The digital gauges consistently gave lower readings than the mechanical heise gauge; however, this data was inconclusive. The licensee decided to retest an MSSV using the heise gauge to compare the as-left set point, which used the digital, with the retest lift pressure. The result showed that the retest setpoint was higher than the as-left resulting in potentially sixteen inoperable safety valves.

The unit was placed in Hot Shutdown in accordance with TS 3.7.1.F and the licensee declared at GSEP UE at 10:26 p.m. on August 26. TS 3.7.1.F requires that the unit be placed in Mode 3 within four hours and allows the unit to remain in Mode 3 for an additional 48 hours. If the system is not made operable within that period, the unit must be in Mode 5, Cold Shutdown within 24 hours.

The sixteen valves were retested and declared operable within the 48 hour time limit and the UE was terminated at 1:20 a.m. on August 29. Further investigation on August 29 revealed that the recorder used to determine the lifting force by the strain gauge was also questionable due to temperature considerations. As a result, four valves were declared inoperable. Discussions between the licensee and Region III management indicated that the licensee was still governed by the LCO declared on August 26. Therefore, the licensee requested discretionary enforcement to avoid violating TS 3.7.1.F. The request was granted by the Regional Administrator. The unit remained in Hot Shutdown until the MSSVs were all retested and reset. On August 30, the UE was terminated.

The unit was taken critical at approximately 4:47 a.m. on August 30, 1989. While rolling the turbine up from 600 RPM to 1800 RPM, a step change of 300 RPM occurred at about 1000 RPM. A problem was suspected in the EHC system. The licensee changed the logic cards and was able to change the point where the step change in turbine speed occurred; however, the speed increase was still unstable. The unit remained in Hot Standby (Mode 2) for further investigation. On August 31, at approximately 8:10 p.m., the unit was finally placed on-line.

The following concerns were raised during this evaluation:

On August 23, the residents reviewed the work packages and requested the calibration certif[illegible]s for the Furmanite equipment. The document showed the date of the last calibration and the calibration frequency for the load cell, strain gauge and recorder. The residents requested the manufacturer's data to substantiate the TREVITEST load cell calibration data for each instrument. This information was not available on site for review and was sent by Furmanite on August 30. The inspectors were concerned that the calibration information was not reviewed by onsite QC or QA organizations prior to the start of the test.

The problems with the MSSVs setpoint settings were caused by the use of digital electronic pressure gauges which have usable environmental temperature ranges of 32°F to 110°F. This temperature limitation was not discovered until August 26. Further complicating the troubleshooting problem were the mechanical heise gauges, one of which did not have a mechanical set (hysteresis test) and another without internal temperature compensation for use in the high temperature environment of the steam tunnel and MSSV house. The licensee's corrective actions for this event will be followed by the resident inspector. It will remain an Unresolved Item (295/89021-06(DRP)).

e. Check Valve Testing in Response to SOER 86-3

Due to recent industry wide concerns on check valve leakage, and in response to Significant Operating Event Report (SOER) 86-3, the licensee has developed a program to diagnostically test and inspect check valves. The program selects valves for testing based on station experience, corporate directive, industry operating experience, and the results of station design review.

Check valves were placed into one of four categories based on CECo Corporate Check Valve directive. These valves will be tested or inspected in accordance with the criteria of the specified category once every four refueling cycles until engineering judgement determines that a different frequency is more suitable. Twenty-five percent of the Category 1 through 4 valves for Unit 1 have been selected for inspection during the 1989 fall refueling outage.

Industry experience shows that check valve internals degrade in a number of ways that cause different types of problems, such as: excessive hinge pin wear, fatigue of the disc to hinge arm connection, or delayed closure due to disc sticking. The retention devices, anti-rotation devices for internal damage, disc and seat surfaces, and determination of adequate "play" in internals will be inspected during this outage.

The valve testing and inspection scope expansion will depend on the nature of the problems found and the potential for making similar valves inoperable.

This is considered an Open Item (295/89021-07; 304/89019-05(DRP)) pending completion and results of the testing.

f. Potential Counterfeit Westinghouse Circuit Breaker

On August 18, 1989, an inspector from the Vendor Branch found one questionable circuit breaker. This breaker is a Westinghouse Model DS-416 circuit breaker which was purchased from Satir American as a refurbrished breaker. The licensee stored the breaker in the warehouse in anticipation of using it on a modification to the fire protection system, during the upcoming Unit 1 outage. The breaker was to replace the supply breaker to a motor driven fire pump. Westinghouse is supplying a new breaker which will be available for installation during the outage.

g. Inadvertent Containment Isolation During Test.

On July 12, 1989, at approximately 10:20 a.m., while performing PT-10, Safeguards Actuation, on Unit 1, several containment isolation valves were inadvertently actuated. This occurred when the test switch for the actuation relay being tested was removed from the test position prior to resetting the Phase A isolation signal. The test switch was returned to the test position and the affected valves were realigned.

The cause of the event was due to personnel error which was worsen by a procedure requiring human factors enhancements. The procedure has been revised to include appropriate caution statements to warn operators of the consequences of improper switch manipulation.

One violation with two examples and one unresolved item were identified.

6. Monthly Maintenance Observation (62703)

Station maintenance activities on safety related systems and components were observed or reviewed to ascertain whether they were conducted in accordance with approved procedures, regulatory guides, industry codes or standards and in conformance with Technical Specifications. Consideration was given to: the limiting conditions for operation while components or systems were removed from service; approvals prior to initiating the work; use of approved procedures; functional testing and/or calibrations prior to returning components or systems to service; quality control records; personnel qualifications and training; certification of parts and materials; radiological and fire prevention controls. In addition, work requests were reviewed to determine status of outstanding jobs and to assure that priority is assigned to safety related equipment maintenance which may affect system performance.

Technical Specifications required surveillance testing on the reactor ventilation and containment isolation systems were reviewed or observed. Consideration was given to: procedures; calibration of test instrumentation; limiting conditions for operation during testing; removal and restoration of the affected components; whether test results conformed with technical specifications and procedure requirements; review of test results by personnel other than the individual directing the test; and correction of any deficiencies identified during the testing. PT-21, "Reactor Coolant System Leakage Surveillance" was reviewed and no problems were noted.

During this inspection period, a Maintenance Team Inspection was conducted by regional inspectors on May 30 through July 24. The results of this inspection were recorded in Inspection Report 50-295/89018; 50-304/89017.

The following maintenance activities were observed or reviewed:

NWR Z63483	Troubleshoot and repair MOV 2 MS006 Pressurizer ALARA
NWR Z83859	Repack 2PCV-RC06

NWR Z83483: The inspector observed the second repair on the valve. The first hold point was placed on the step which adjusted the clutch tripper. A second hold point later in the package required the QC inspector to verify that the valve could be manipulated by the handwheel. The QC inspector verified the free motion of the wheel and signed off both hold points. While the inspector agreed that since the wheel turned freely, the tripper was adjusted correctly, the inspector questioned the philosophy of QC hold points and the role of QC during maintenance activities. The resident staff discussed these concerns with the QC supervisor who issued a letter to refamiliarize and reemphasize the definition of a hold point to his staff. The maintenance team inspectors also reviewed this package and had additional concerns. (See Inspection Report 295/89018; 304/89018)

NWR 83859: The inspector attended the ALARA and job planning meeting. The briefing appeared to be complete and contained sufficient details to perform the job.

c. History of Packing Leaks on PCV-RC06 and PCV-RC07

The pressurizer spray valves (PSV) used on both Unit 1 and 2 are four inch vee-ball control valves manufactured by Fisher controls. There have been several events involving packing leaks on PSVs which required bringing the affected unit off-line due to high reactor coolant system (RCS) leak rate.

Both PSVs on Unit 1 were rebuilt during the last refueling outage and have not leaked since being returned to service in May 1988. During a forced outage earlier this year, the nuts on the packing follower were checked and found to be tight.

Unit 2 PSVs were only repacked during the last refueling outage (Fall 1988) since the parts necessary to rebuild the valves were not available. By February 19, 1989, after being in service for only six weeks, both PSVs began to leak. Mechanical maintenance personnel found the packing follower to be loose and tightened the packing follower nuts until the leakage stopped. Since the possibility existed that the packing follower nuts might have loosened due to vibration, each packing follower stud was double nutted. 2PCV-RC07 was isolated following the repair to keep as a spare should 2PCV-RC06 develop a packing leak.

The reactor coolant system leak rate increased to 4.5 gpm on July 22, 1989. 2PCV-RC07 was unisolated at this time providing the unit operator with only one operable pressurizer spray valve. 2PCV-RC06 was then isolated reducing RCS leak rate below 1 gpm. On July 29, mechanical maintenance personnel performed a hot retorque on 2PCV-RC06 while it was isolated. A hot retorque involves tightening the packing follower and then stroking the valve several times. These steps were repeated until no further adjustments could be made. Once the hot retorque had been completed, 2RC0021 was opened partially to pressurize 2PCV-RC06. No leakage was observed with the PSV pressurized to RCS pressure.

The packing on 2RC0021 was tightened three-fourths of a turn on each packing follower nut since leakage was observed in the sight glass coming from 2RC0021 when 2PCV-RC06 was initially isolated on July 22.

2PCV-RC06 was reisolated following the repair to keep it as a spare should 2PCV-RC07 develop packing leaks in the future.

The leakage past the packing is due to packing consolidation. After a packing is loaded into a stuffing box and compressed by the gland follower, it undergoes two types of consolidation-initial consolidation and in-service consolidation. Initial consolidation occurs shortly after installation as the packing conforms to the stuffing box and stem. Initial consolidation can be corrected by good installation practices. In-service consolidation occurs over the service life of the packing due to packing wear, collapse of packing voids, packing creep, and loss of packing volume due to volatilization of fillers. The resulting in-service consolidation results in a loss of gland load and eventual leakage. In-service consolidation can be compensated with the use of "live loading" (using a spring loaded gland follower).

Degraded conditions of the valve stem or stuffing box also contributes to the packing leakage problem. Although, the graphite packing used on the PSV will out perform other packing materials, it is not as forgiving as asbestos packing and will not overcome leakage problems associated with scored or pitted stems. An inspection of Unit 1 spray valves after disassembly revealed some scoring on the stem in the packing box area. This scoring could have been caused by the hooks used to remove the packing and/or from the cutting action of the steam from previous packing leaks. After Unit 2 spray valves were repacked (Fall 1988), they leaked after only six weeks of service.

The pressurizer spray valves used at Zion have a deep stuffing box with a lantern ring supplying a leakoff line. The valve is installed with the stem in the horizontal position.

A Electric Power Research Institute (EPRI) report concluded that improved packing systems could be obtained by implementing three recommendations:

- a reduce packing depth;
- application of graphite packing; and
- application of live loading.

The procedure for packing the valves will specify the proper torque value and not rely on the mechanic's judgement which is the practice presently in use.

All three improvements listed above will be implemented in Modification 22-1(2)-89-19 which is scheduled to be installed on Unit 2 during the next refueling outage (Spring 1990). The modification will be installed on Unit 1 during the refueling outage scheduled for Spring 1991.

No violations or deviations were noted.

7. Licensee Event Reports (LERs) Followup (92700)

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished in accordance with Technical Specifications. The LERs listed below are considered closed:

UNIT 1

LER NO.	DESCRIPTION
295/89009	Inadvertent Start of Auxiliary Feedwater Pump Due to Personnel Error

UNIT 2

LER NO.	DESCRIPTION
304/85029	Purge Isolation due to Low Temperature and High Radiation Signal

On June 20, 1989, while performing PT-7A, Starting Procedure for Auxiliary Feedwater (AFW) Pump Lube Oil Pump, the AFW pump was inadvertently started locally but could not be stopped. The inadvertent start was caused by operator distractions at the remote shutdown panel (RSP) and inconsistencies in the pump switch layout between the AFW trains. Investigations showed that the START/STOP labelling on the pump switch was reverse, which would not allow the pump to be stopped with the switch in the STOP position. The licensee changed the labelling and intends to modify the switch locations at the RSP to establish consistency. This LER is considered closed.

On December 1, 1985, with Unit 2 in cold shutdown, during a Unit 2 containment purge, the running 2A purge supply fan and 2A exhaust fan tripped. The containment purge inlet and outlet isolation valves 2AOV-RV0001, 2AOV-RV0002, 2AOV-RV0003, 2AOV-RV0004 closed, and the "Air Exhaust Stack Radiation High" annuciator alarmed.

The cause of this isolation was a spurious high radiation alarm from the containment purge exhaust stack air particulate monitor 2RT-PR09C which isolated the purge inlet and outlet valves and tripped the running purge and exhaust fans.

The root cause of this event was a spurious spike on monitor 2RT-PR09C caused by voltage spiking on the AC power feed to the monitor. A metering capacitor in an AC line filter was replaced by one with a higher value (10 microfarads) and the spiking problem has by one recurred. Therefore, this LER is considered closed.

No violations or deviations were identified.

8. Temporary Instructions (2500/27)

TI 2500/27 - Inspection Requirements for NRC Compliance Bulletin 87-02, "Fastener Testing to Determine Conformance with Applicable Material Specifications". Attachment 1 of the TI lists the sites and applicable portions of the TI which are to be inspected. No action is required for the Zion station, therefore, this TI is considered closed.

No violations or deviations were noted.

9. Training (41400)

During the inspection period, the inspectors reviewed abnormal events and unusual occurrences which may have resulted, in part, from training deficiencies. Selected events were evaluated to determine whether the classroom, simulator, or on-the-job training received before the event was sufficient to have either prevented the occurrence or to have mitigated its effects by recognition and proper operator action.

Personnel qualifications were also evaluated. In addition, the inspectors determined whether lessons learned from the events were incorporated into the training program.

Events reviewed included the events discussed in this report. In addition, LERs were routinely evaluated for training impact.

No violations or deviations were noted.

10. Quality Program Effectiveness (35502)

a. Clarification of the Definition of a Hold Point

While reviewing maintenance activities, the inspectors questioned the licensee's use of Quality Control (QC) hold points. In order to prevent confusion and inconsistencies in the interpretation and application of QC hold points, the licensee provided the following definition:

"A designated stopping place prior to, during, or following a specific activity to verify that the activity is performed correctly and completely. When a Hold Point is indicated next to a work activity, work cannot be done on this step in the procedure until the organization establishing the Hold Point initiates the inspection activity or the Hold Point is formally waived by them...the organization establishing the Hold Point must be present before the work activity may proceed."

The QC hold point issue and the role of Quality Assurance and Quality Control inspectors will be reviewed due to the concerns raised in the testing of the MSSVs and maintenance work on the MS006 valve.

b. Progress on Program Changes

The management changes recommended by the INSTP Program, (a management assessment by General Electric), are nearly complete. The Performance Improvement Plan (PIP), a program established to improve plant performance is currently being formalized for implementation. This program includes all licensee commitments to the NRC, Institute of Nuclear Plant Operations, Commonwealth Edison Corporate Assessments, Quality Assurance findings, and station identified improvement items. There are over 300 PIP items complied by the Regulatory Assurance Group. The 60 most significant PIP items are being prioritized for presentation to Region III management on September 12, 1989, during the monthly NRC and licensee meeting, at the Zion Station. The implementation of the PIP items will be monitored.

No violations or deviations were noted.

11. Open Items

Open Items are matters which have been discussed with the licensee which will be reviewed further by the inspector and which involve some action on the part of the NRC or licensee or both. Six Open Items disclosed during this inspection are discussed in Paragraphs 2, 4e, 5a, and 5e.

12. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, items of noncompliance or deviations. Two Unresolved Items disclosed during this inspection are discussed in Paragraphs 4d and 5d.

13. Exit Interview (30703)

To promote better communication and understanding, the resident inspector staff met with licensee management and all operations crews during this inspection period. Topics discussed included the roles and responsibilities of the NRC inspectors as defined in 10 CFR Part 50.70, the history and purpose of the RI program, the RI and operations interface during program implementation, how NRC inspector perceptions are influenced by observed control room professionalism and the purpose of RI questions and techniques. An overview of these meetings was presented to regional personnel as a weekly training topic on August 7, 1989.

On July 7, Senior Commonwealth Edison management made a presentation to Senior Region III management on management changes and performance improvement programs being implemented at the Zion Station. The implementation schedule of these programs covered the range of in process to several years.

On August 8, the first monthly scheduled meeting between regional and licensee management was held at Zion Station. The topics discussed were: Zion Station's current performance in areas that needs improvement and the licensee action to implement changes in these areas. A draft with approximately 300 performance improvement items was presented by the licensee. Specific priorities for implementation had not been assigned at the time of this meeting. The licensee committed to have the top 60 priority items assigned and present the status of implementation at the next meeting scheduled for September 12, 1989.

The inspectors met with licensee representatives (denoted in Paragraph 1) throughout the inspection period and at the conclusion of the inspection on September 5, 1989, to summarize the scope and findings of the inspection activities. The licensee acknowledged the inspectors' comments. The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents or processes as proprietary.